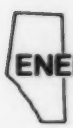
ULTIMATE POTENTIAL FOR GAS IN ALBERTA

NOVEMBER 1979



ENERGY RESOURCES CONSERVATION BOARD
ALBERTA, CANADA

Published by:

Energy Resources Conservation Board
603 Sixth Avenue S.W.
Calgary, Alberta
T2P 0T4

Telephone (403) 261-8311

Telex 03-821717

Price: $5.00

CONTENTS

1	Decision	1
2	Findings and Observations	2
3	Introduction	14
4	Submission of Alberta Gas Trunk Line Company Ltd.	20
5	Submission of Alberta and Southern Gas Co. Ltd.	22
6	Submission of Amoco Canada Petroleum Company Ltd.	23
7	Submission of Canadian Hunter Exploration Ltd.	25
8	Submission of Canadian-Montana Pipe Line Company Limited	27
9	Submission of Canadian Petroleum Association	28
10	Submission of Dome Petroleum Limited	30
11	Submission of Esso Resources Ltd.	32
12	Submission of Home Oil Company Limited	34
13	Submission of Hudson's Bay Oil and Gas Company Ltd.	36
14	Submission of Independent Petroleum Association of Canada	37
15	Submission of Pan-Alberta Gas Ltd.	39
16	Submission of Pan-Canadian Petroleum Limited	40
17	Submission of TransCanada Transmission Company Limited	42

Appendix

A.1 Notice of Hearing

A.2 Definitions

A.3 Table of Geological Formations

FIGURES

1	Trends in Annual Additions to Initial Marketable Gas Reserves	5
2	Trends in Annual Additions to Initial Marketable Gas Reserves	6
3	Annual Drilling Footage	9
4	Alberta's Established Marketable Gas Reserves Growth Forecast	11

TABLES

1 Summary - Ultimate Reserve Submissions 19

1 DECISION

As indicated in ERCB Report 79-B, "Summary Report on Alberta Gas Reserve and Removal Matters", the Board adopted a range of 130 to 140 Tcf as representing the initial ultimate potential for gas in Alberta under gas prices and technological advances that can now be anticipated with a high degree of certainty. The equivalent range rounded in metric terms is 3.7 to 3.9 x 10^{12} m^3. For administrative purposes, the Board will use the mid-range value of 135 Tcf or 3.8 x 10^{12} m^3. These quantities are expressed on the basis of gas having a heating value of 37.4 megajoules per cubic metre or the equivalent heating value of 1000 Btu per cubic foot.

The Board believes that the ultimate potential could increase significantly to a value in excess of 200 Tcf or 5.6 x 10^{12} m^3. This potential could be realized if the net value of gas to producers substantially exceeds the Board's current estimates and/or there are technological breakthroughs which markedly extend the industry's ability to physically and economically produce gas from unconventional sources. The large volumes of gas trapped in ultra-low permeability sands represent the currently most obvious potential additional source.

In the notice of hearing for the proceeding, the Board solicited submissions respecting the initial ultimate potential for co-produced ethane, propane, butanes, pentanes plus and sulphur. In view of the limited response received, the Board has decided to postpone its decision on these matters until a study can be performed relating the expected distribution of the future gas reserves to gas composition data in the Board files. Preliminary estimates using historical co-product/marketable gas ratios are provided in the Board's annual reserves report, ERCB Report 79-18[1].

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1 Alberta's Reserves of Crude Oil, Gas, Natural Gas Liquids and Sulphur, at 31 December 1978. ERCB Report 79-18, August 1979.

2 FINDINGS AND OBSERVATIONS

2.1 Ultimate Potential for Gas - Current Technology and Confidently Anticipated Economic Conditions (referred to in this report as "gas from conventional sources")

The submissions and evidence presented at the hearing were of considerable assistance to the Board in its assessment of the ultimate potential for gas from conventional sources. In general, the submittors used a combination of geological/volumetric and geological/statistical methods to estimate Alberta's ultimate gas potential. Geological/volumetric methods generally involve the determination of a yield ratio for a densely explored region in terms of either a volume of gas per volume of sediment available or a volume of gas per unit of exploratory footage drilled, and the application of that ratio to relatively unexplored regions. Geological/statistical methods usually involve a detailed statistical projection based on an analysis of reserve geological, geophysical or geochemical data for a given area. Each method has, in the Board's view, certain advantages and disadvantages. For example, volumetric methods such as a projection of finding rates versus either wells or footage drilled are generally fairly simple to apply and understand. On the other hand, they can give misleading results particularly if economic and technological factors change radically. Statistical methods such as those involving a detailed analysis of the size and distribution of pools in a particular geological formation are complex but should provide a reasonable perspective of the potential of a given region over a broad range of circumstances. Each method depends upon the adoption of important assumptions respecting either relatively unexplored areas of the province or relatively unexplored geological formations. The methods used by submittors generally gave a broad estimate of the ultimate potential. In several cases, particularly where statistical methods were used, the submittors related their estimates to the probability of realization.

In general, the Board believes that the volumetric techniques tend to provide somewhat optimistic estimates because they often assume that unexplored areas will be as productive as areas explored to date. The Board agrees with various statements presented regarding the inexactness of these methods. Many of the geological/volumetric methods relied heavily on subjective judgement factors, which, combined with a lack of documentation regarding these factors, preclude a definitive assessment of the results.

The play analysis method, a statistical approach used by several submittors, appears to the Board to be somewhat better than volumetric techniques in accounting for the many geological vageries associated with ultimate gas potential estimates. However, because it relies heavily on the knowledge and experience of the person carrying out the analysis, the results obtained by several interpreters may fall in a rather wide range.

Ten submittors presented estimates of Alberta's ultimate gas potential from conventional sources. The estimates range from 114 Tcf to 205 Tcf. The Board understands that the lower estimate, that of Esso Resources Ltd., has been amended and increased to 129 Tcf in a recent submission to the National Energy Board. Allowing for this change, the mid-point of the industry estimates is some 165 Tcf and the arithmetic average is some 155 Tcf. As indicated previously, the Board believes that some of the higher estimates should be partially discounted because it may be overly optimistic to extrapolate experience from developed to undeveloped areas.

In addition to reviewing the submissions and evidence presented at the hearing, the Board also examined the performance of the industry over the last 30 years in the discovery and development of gas reserves in the province. In the Board's view, the historical record has considerable significance and should provide a basis for assessing future developments, particularly over the next 5 to 10 years. In addition,

it also provides a cross-check with the more theoretical analyses made by the several submittors.

Some 15 years ago the Board estimated the province's ultimate gas reserves at 100 Tcf. By the late 1960's and early 1970's it was concerned that this estimate might be too high, particularly since many ultimate reserve estimates by other bodies were lower. However, in 1973 the Board decided to increase its ultimate reserve estimate to 110 Tcf to reflect the impact of expected higher gas prices. It is now clear that even the 110 Tcf estimate is too low and needs to be revised.

Figure 1 summarizes the annual additions of gas reserves as estimated by the Board over the 30-year period. The wide variation in annual additions shown in the figure is credible, having regard for the varying circumstances that have prevailed during the past 30 years and the uncertainties associated with exploratory activities. The average annual addition for the 30-year period is some 2,9 Tcf. While the data is scattered, it would support an upward sloping trend line as indicated in Figure 1. This suggests a continually improving exploration outlook which is not a reasonable premise for predicting future reserve additions indefinitely into the future and, therefore, the Board discarded this interpretation. Figure 1 also shows the average annual addition for each of the three decades. Not only have the additions been greatest during the last decade but the growth during the last few years of the decade has been at the highest rate in the province's history. It is apparent that in 1973 a significant change took place in the gas exploration environment. Figure 2 compares the annual additions to reserves for the 1950 - 1972 and 1973 - 1978 periods. The average annual addition during the former period was some 2.4 Tcf whereas during the latter period the average additions almost doubled, to some 4.4 Tcf.

The Board has reviewed the circumstances relating to exploration and development during these two periods in order to identify underlying forces that may influence activity in the future and may help to explain

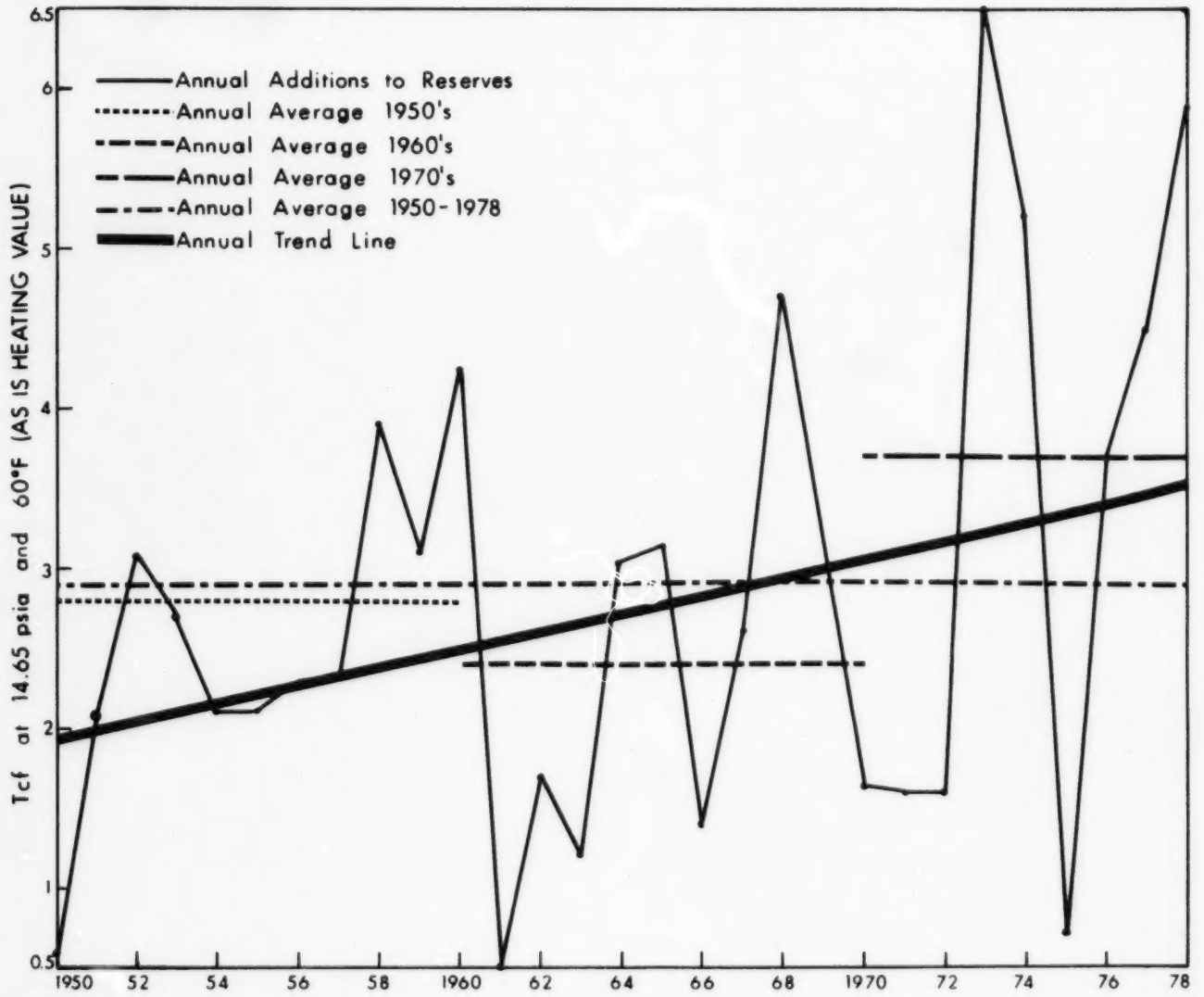

FIGURE 1 TRENDS IN ANNUAL ADDITIONS TO INITIAL MARKETABLE GAS RESERVES

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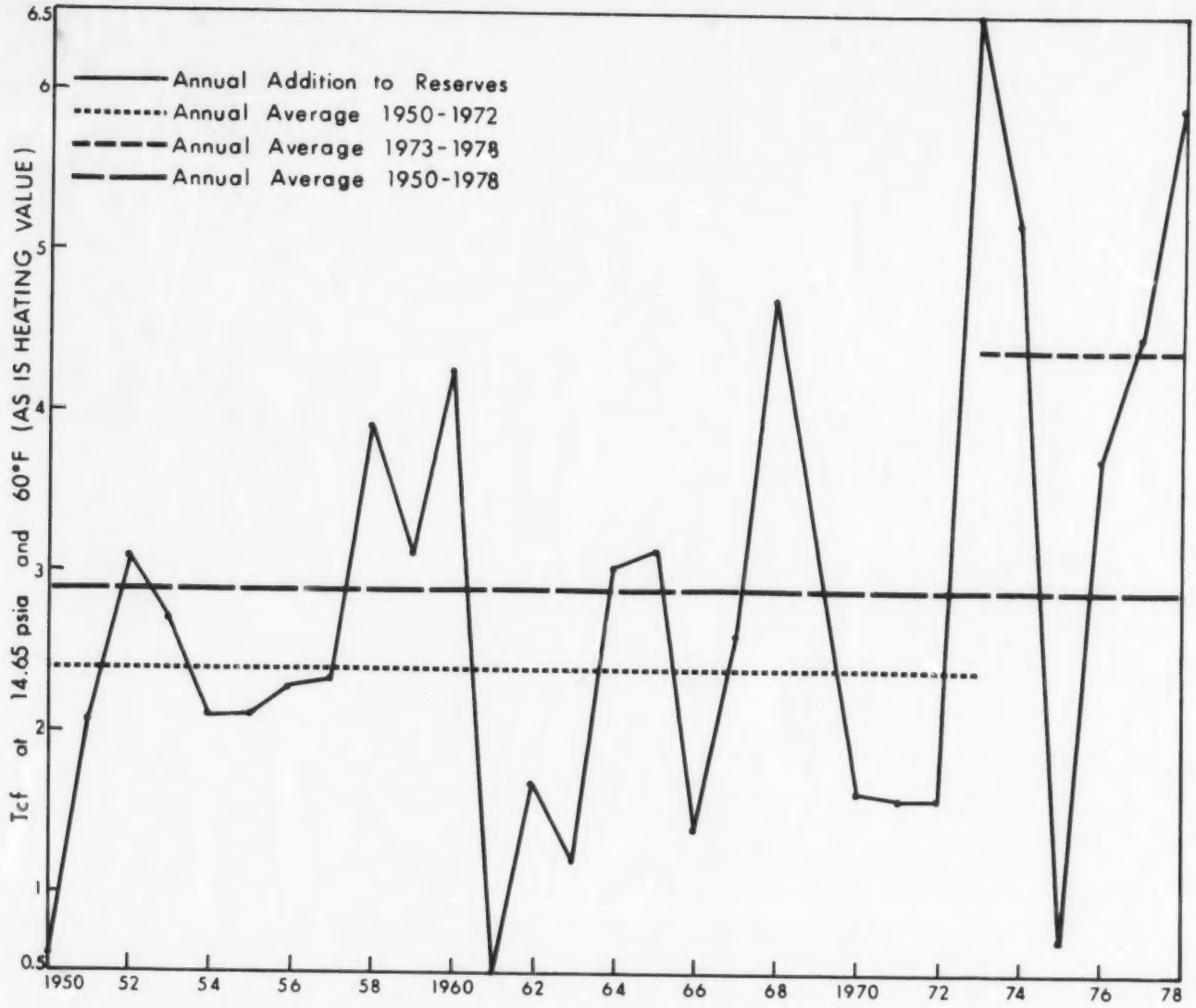

FIGURE 2 TRENDS IN ANNUAL ADDITIONS TO INITIAL MARKETABLE GAS RESERVES

why its previous assessment of ultimate reserves has proven to be too low. Several factors have been identified. Some of them, such as the price of gas, were recognized in making the previous estimate but the full impact was not appreciated. Certain factors, such as exploratory drilling incentives, occurred after the Board prepared its estimate. A summary of the more important factors influencing gas reserve additions is provided below:

a) The Price of Gas and the Net Returns to the Producer

The major impact that gas prices and producer net-backs have on exploration has been recognized for many years. The substantial reserve additions recorded by the Board in 1973 and 1974 were clearly the product of improved economics. At that time it was recognized that the projected higher gas prices would result in improved recovery from most pools and would make economic the development of shallow gas reserves in southeastern Alberta. The Board did not, however, fully appreciate the magnitude of sub-marginal gas reserves that would be converted to economic reserves under the improved economic environment.

b) The Incidence of In-Place Gas Reserves

Developments during the last few years have demonstrated that natural gas appears present in virtually all sections of the geological column and is present throughout the province extending from the deep foothills sediments to the shallow eastern sediments. Whether these in-place reserves can be converted to established reserves largely depends upon economic factors. The impact of improved producer net-backs is illustrated by the substantial increase in the number of pools included in the Board's reserve files. Currently the Board has established reserves in over 9000 pools and the total is increasing rapidly. The importance of these small accumulations is further indicated with reference to the 1978 reserve additions, of which 2.9 Tcf was attributed to pools with established reserves of less than 10 Bcf. Additionally, there have been thousands of minor gas shows so small that established reserves have not been recognized.

c) Exploratory and Development Incentives

The combination of higher producer net-backs, a substantial inventory of potential gas exploration prospects, and various government exploratory incentive programs has resulted in a substantial increase in drilling activity during the last few years. This is illustrated in Figure 3. The Board believes that the impact on gas exploration is much greater than shown in the figure since exploration during the 1950's and 1960's was mainly oil-oriented, but during the last decade it has been predominantly gas-oriented.

d) The Market Outlook for Gas

During the early 1970's reserve growth in Western Canada did not keep pace with market requirements and therefore there appeared to be an assured market for the expanded exploration and development programs. Market requirements did not increase as expected, however, and the rapid growth in established reserves resulted in substantial shut-in gas productive capacity. While this excess capacity has undoubtedly had some dampening effect on development, the overall impact to date is probably modest because of the prospects of new export sales.

e) New Gas Exploration Plays

The combined effect of the foregoing factors was to provide a significantly more favourable climate for gas exploration in Alberta. One of the consequences of the increased activity was the extension of exploration into areas that had been relatively unexplored previously. One of these areas, the Deep Basin of northwest Alberta, promises to be particularly prolific, both in terms of conventional and non-conventional reserves, and is expected to have a significant impact on ultimate reserves.

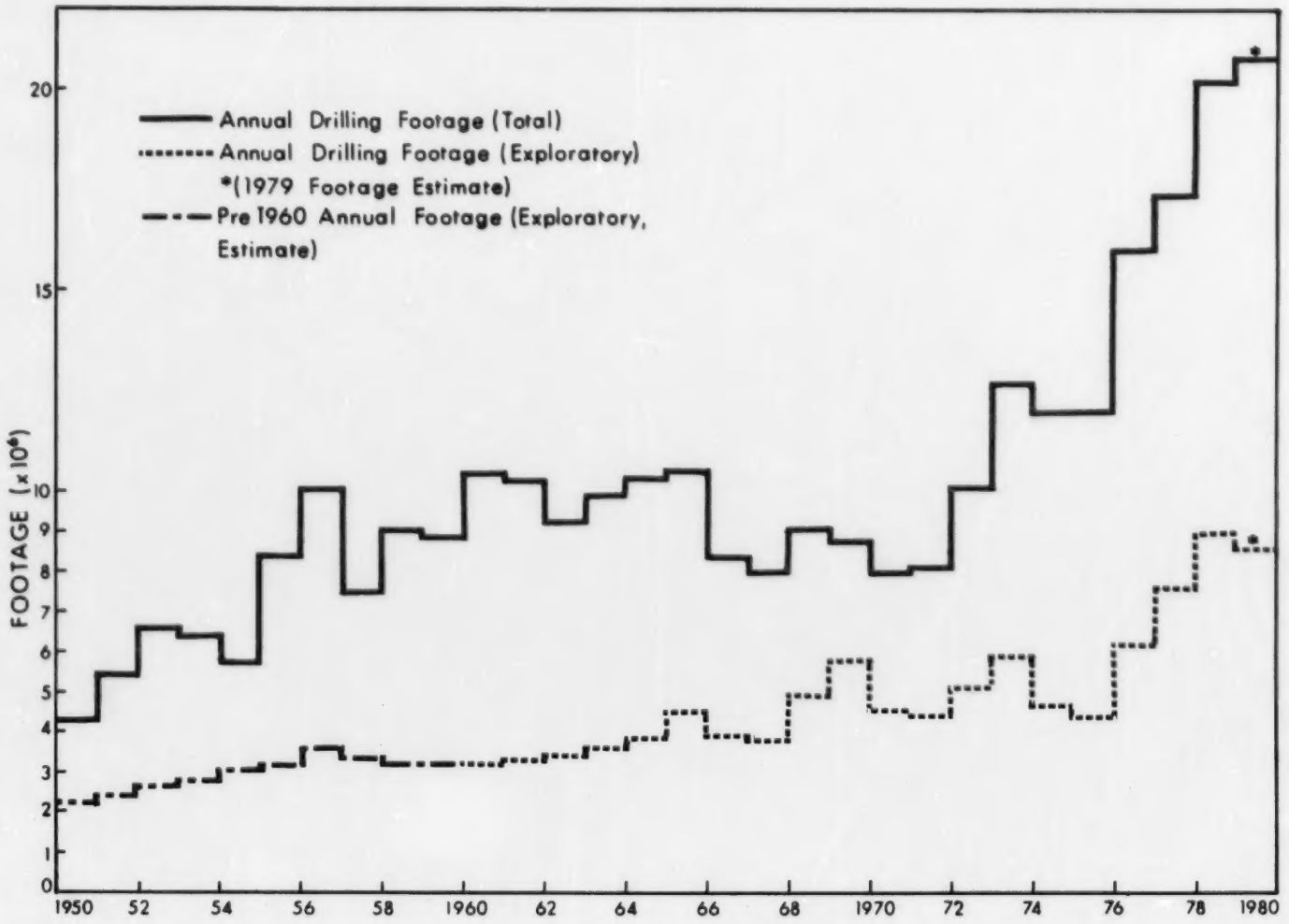

FIGURE 3 ANNUAL DRILLING FOOTAGE

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In summary, the exploration for and the development of gas reserves in Alberta over the last 30 years has in effect taken place under two distinct regimes. The period prior to the new energy price outlook (ie. prior to 1973), was characterized by low gas prices and minimum incentives for gas exploration and development. During that era only the more attractive reserves warranted development, and exploration for gas was seriously inhibited. The new price regime not only made gas exploration much more attractive economically, but it in effect converted a substantial volume of in-place reserves to potentially marketable gas reserves, thus providing a large inventory of gas exploration prospects.

Furthermore, the exploratory incentive programs implemented by the Alberta and federal governments provided additional encouragement. The combination of these two factors has, in the Board's view, resulted in an abnormal growth in exploration and reserve additions. It is difficult to estimate how long these circumstances will prevail. The Board expects, however, that once the adjustment has been fully realized, reserve additions will return to what can be considered a more normal rate. Of course, should there be further significant improvements in the economics of exploring for and developing gas reserves, a similar process can be expected to take place.

The Board believes that the foregoing interpretation of the historical exploration and development data, coupled with the broad industry analyses of future gas reserves potential in the province, provides a basis for extrapolating the future growth of gas reserves. Furthermore, such a blending of actual experience with theoretical analyses provides a means of judging the realism of the theoretical estimates. In developing its projection of future reserve additions, the Board decided that its estimate should be reasonably conservative and one that could safely be relied on. It concluded that reserve growth would continue at the more or less current high level for the next few years and then decline fairly rapidly. The projection is shown in the lower portion of Figure 4, and it results in an ultimate gas reserve of some 130 Tcf

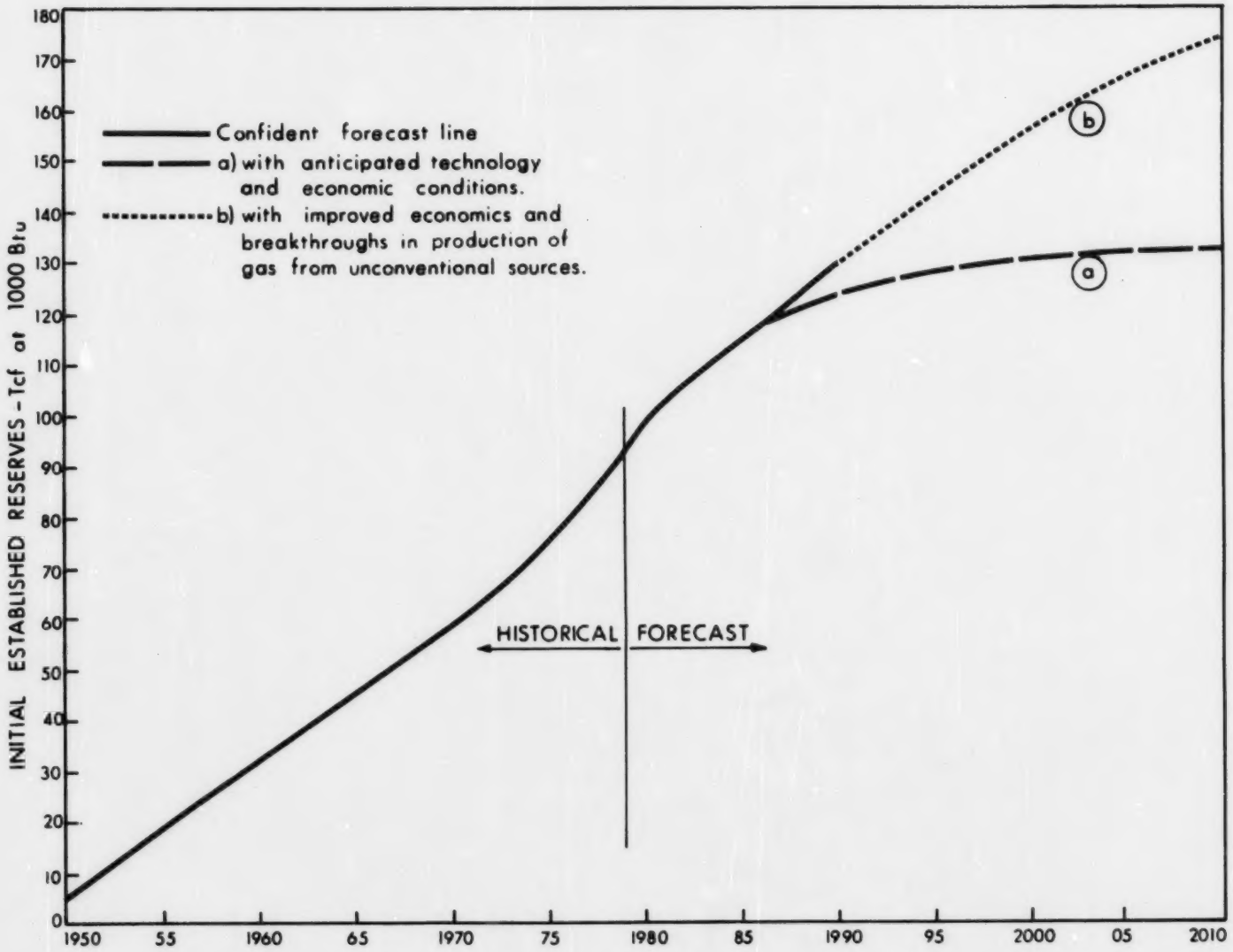

FIGURE 4 ALBERTA'S ESTABLISHED MARKETABLE GAS RESERVES GROWTH FORECAST

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to 140 Tcf. This estimate is on the low side of the range of estimates presented by the submittors. The Board believes this estimate to be a realistic minimum ultimate potential which can safely be counted on.

The Board intends to closely monitor exploratory activities and the annual additions to reserves and, should they deviate significantly from the projection shown in Figure 4, it would then adjust the forecast and its ultimate reserve estimate in an appropriate manner.

2.2 Ultimate Potential - Significantly Altered Economic Conditions and Technology (referred to in this report as "unconventional reserves")

In its notice of hearing regarding Phase 1, the Board requested submission of data regarding "gas expected to be economically recoverable only under significantly improved technology". During the hearing some evidence was introduced by AGTL, Amoco, CPA, Canadian Hunter, and Esso[1] regarding the potential of unconventional gas reserves from the Deep Basin area of Alberta and other unconventional sources. AGTL, Amoco, and Canadian Hunter presented estimates which exceeded 200 Tcf for the Deep Basin area. CPA recognized that extremely large in-place reserves are present within the Mesozoic section of the Deep Basin but did not provide an estimate of unconventional reserves. Esso made reference to potential unconventional reserves in both the Deep Basin and in coal seams and pointed out the need for significantly improved technology spurred on by readily available markets and a favourable economic climate in order to realize development.

The Board recognizes that evaluation of the low permeability sands of the Deep Basin area is currently being conducted by several companies, but believes that major changes in economics and improved technology are required to recover significant gas reserves from this source.

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1 See Section 2.2 for an explanation of these abbreviations.

Based on the evidence presented by AGTL, Amoco and Canadian Hunter, the Board concludes that at least 60 to 70 Tcf of unconventional gas reserves can be expected to be recovered if gas prices go well beyond those currently anticipated by the Board and/or if substantial technological breakthroughs are achieved. Should either or both of those situations occur, Alberta's ultimate potential for gas could increase significantly and may well be in excess of 200 Tcf. The Board is not officially recognizing this latter number at this time, but presents it as an indication of the ultimate gas potential of the province, having regard for both conventional and unconventional reserves. The upper portion of Figure 4 shows how this ultimate potential, which exceeds 200 Tcf, might be developed.

3 INTRODUCTION

3.1 Purpose of Estimating Ultimate Gas Potential

The objeccive of estimating ultimate potential of gas is to provide the public, the provincial and federal governments, and the petroleum industry with overall views respecting Alberta's future gas resource supply. As a practical matter, the ultimate potential of gas is reported on a province-wide basis even though the potential may vary considerably between local subregions. Under the Board's protection formula, the ultimate potential is involved in decisions respecting applications to remove gas from the province.

The first investigations made by the Energy Resources Conservation Board in 1955 resulted in an estimated ultimate gas potential of 60 to 100 Tcf (1.7 to 2.8 x 10^{12} m^3). From 1964 to 1972 the Board estimated an ultimate potential of marketable gas in Alberta of 100 trillion cubic feet (2.8 x 10^{12} m^3). The Board increased the estimate to 110 Tcf (3.1 x 10^{12} m^3) in 1973, after taking into account markedly improved economics as a result of gas price increases. The rapid pace of drilling activities since then provides much additional information to permit an extensive review of the ultimate gas potential as now seen in 1979.

3.2 The Hearing and Participants

In the Notice of Hearing, Proceeding 780491, dated 29 August 1978 (Appendix A.1), the Board announced a two-phase public hearing respecting (a) Phase I - the ultimate reserves of gas and co-products, and (b) Phase II - the formulae for determining the amount of gas surplus to Alberta needs. This report deals only with Phase I.

In response to the Board's request, 14 written submissions were received from industry representatives respecting this phase of the hearing.

For the purpose of hearing representations respecting Phase I, a public hearing of the applications was held before the Energy Resources Conservation Board commencing on Tuesday, 15 February 1979, with V. Millard, G. J. DeSorcy, P.Eng., and N. Strom, P.Eng. sitting. The following table lists those who appeared at the hearing.

THOSE WHO APPEARED AT THE HEARING

Principals and Representatives (Abbreviations used in Report)	Witnesses
Alberta Gas Trunk Line Company Limited (AGTL) A. J. Hopwood, Q.C. F. Foran	C. R. Winter, P.Eng. V. B. Kromand, P.Eng.
Alberta and Southern Gas Co. Ltd. (A&S) J. R. Smith, Q.C.	G. M. Malin, P.Eng. D. McMorland, P.Geol.
Amoco Canada Petroleum Company Ltd. (Amoco) H. L. Hooker	C. O. Grasdal, P.Eng. H. J. Sullivan D. Gieck, P.Eng. H. Simons M. Trethart, P.Eng.
Canadian Hunter Exploration Ltd. (Canadian Hunter) G. F. Hulme	R. E. Wyman K. R. MacGregor, P.Eng. P. K. Cole, P.Geol.
Canadian-Montana Pipe Line Company Limited (Canadian-Montana)	P. Madison A. F. Griffith, P.Eng.
Canadian Petroleum Association (CPA) D. B. Macnamara	E. W. Best, P.Geol. G. Grant H. Simpson, P.Eng.
*Consumers' Gas Company (Consumers') J. H. Farrell	

* Companies that filed a submission for purposes of argument and cross-examination (ie. no information on ultimate reserves).

THOSE WHO APPEARED AT THE HEARING (Continued)

Principals and Representatives (Abbreviations used in Report)	Witnesses
Dome Petroleum Limited (Dome) V. F. Scott	E. J. Muchoski D. A. Nikiforuk, P.Eng. J. P. Twyman, P.Geol. J. R. Britton, P.Geol. J. D. Macgowan, P.Eng.
*Dow Chemical of Canada Limited (Dow) F. A. Lundberg	
Esso Resources Ltd. (Esso) R. T. Booth	R. Wilson, P.Eng. D. Jardine, P.Geol. C. Zinkan
Home Oil Company Limited (Home) T. S. Hoar	W. H. Waddell, P.Geol. F. G. Young M. E. Booth, P.Geol.
Hudson's Bay Oil and Gas Company Ltd. (HBOG) N. G. Sander	K. R. Kirkness, P.Eng. P. R. Brown, P.Eng.
Independent Petroleum Association of Canada (IPAC) C. K. Yates	G. Last, P.Eng. A. E. Potter, P.Eng. W. Hennessey, P.Eng. D. Nikiforuk, P.Eng. K. R. Evans, P.Eng.
*Norcen Energy Resources Limited (Norcen)	
Pan-Alberta Gas Ltd. (Pan-Alberta) J. Stein	M. E. Kilik, P.Eng.
Pan-Canadian Petroleum Limited (Pan-Canadian) D. G. Hart	R. H. Mackie T. Lawrence, P.Eng. L. Mathe, P.Eng.
TransCanada PipeLines Limited (TransCanada) E. W. H. Mallabone	D. C. Fonteyne, P.Geol. D. R. O. Haines, P.Eng.
*Westcoast Transmission Company Limited (Westcoast)	
Energy Resources Conservation Board staff (Board staff) G. H. Stafford, P.Geol. F. J. Mink, P.Eng. J. J. Maguire, P.Eng.	

3.3 Methods of Estimating Gas Potential

Predicting undiscovered gas potential is difficult because of geological uncertainty, the economic, political and technological uncertainties, and the subjective judgement necessary respecting many inter-related facts and ideas. In making ultimate potential gas estimates, two general approaches are used: geological/volumetric and geological/statistical.

Geological/Volumetric: In this method, two approaches are generally used: volume of sediments, and performance measurements. In the volume of sediments approach, the ultimate reserve potential of relatively unexplored areas is estimated on the basis of analogies with known explored areas. In the performance measurements approach, reserves found by some measure of exploration drilling and/or development drilling effort are extrapolated to a final drilling density. Yields, usually expressed in billions of cubic feet per cubic mile, billions of cubic feet per mile drilled, or as some other ratio, are applied to the relatively unexplored areas to determine their potential.

Geological/Statistical: This approach entails the use of various methods of prediction techniques, based on the probability analysis of geological data. The statistical methods include size distribution of oil and gas pools, use of past finding rates, evaluation of "by-passed" gas in randomly selected abandoned wells, and play horizon analysis. Monte Carlo simulations incorporating probability distributions for geological parameters are sometimes used in conjunction with the above methods.

Numerous combinations of the geological/volumetric and geological/statistical techniques were used by the submittors in their presentations to the Board respecting Phase I.

3.4 Format of Report

Estimates of ultimate potential of gas for all or portions of Alberta were provided by 14 submittors, whose estimates are summarized by category of reserve in Table 1. This report deals with the written and oral presentations made to the Board and with the findings of the Board on the evidence rendered. This report also briefly summarizes each submission as to the methodology used to estimate the ultimate potential of gas, and includes each submittor's estimate of the ultimate potential of gas in Alberta.

In its notice of hearing, the Board invited submissions respecting the initial ultimate recoverable reserves of co-produced ethane, propane, butanes, pentanes plus and sulphur, as classified in item 3 of the Notice of Hearing. This information, which is supplementary to the primary evidence on ultimate gas potential, will be recognized and published by the Board in its regular annual reserves report.

A copy of the Notice of Hearing, definitions of various pertinent terms contained within this report, and a table of formations are included in this report as Appendix A.

TABLE 1 SUMMARY - ULTIMATE RESERVE SUBMISSIONS
(As Is Basis - Tcf)

COMPANY	ESTABLISHED RESERVES	APPRECIATION OF ESTABLISHED RESERVES	ADDITIONS DUE TO BY-PASSED GAS	ADDITIONS DUE TO NEW DISCOVERIES & IMPROVED ECONOMICS	ADDITIONS DUE TO NEW DISCOVERIES & IMPROVED ECONOMICS - CONVENTIONAL DEEP BASIN	PROPOSED ULTIMATE POTENTIAL CONVENTIONAL GAS	UNCONVENTIONAL GAS RESERVES	REMARKS
ERCB (Report 77-18)	76 (80.5)[1]	7		27		110		[1]based on 31 Dec. 1977
AGTL	80.5	8.6		70.1-91	30-48[3]	159.2[2] (159.2-189.2 -198.1)	12-30[5]	[2]based on 70.1 Tcf for future additions
								[3]estimates not included in the proposed ultimate potential
A & S		14.5				127[4]		[4]estimate provided during direct testimony
AMOCO	80	11-16	30-35	73-92		194-223	116-192[5]	
CANADIAN HUNTER					90[5]		174[5]	[5]estimates for Alberta Deep Basin only
CANADIAN-MONTANA	0.33[6]					0.76[6]		[6]study limited to four sub areas Twps 1-10, Rge 1-12, W4M
CPA	77.5	6		67.5		151		
DOME	75[7]			62.1		137.1		[7]at 31 Dec. 1976
ESSO	78.8	4.8		16.3-47.1		109.6[8]		[8]based on a mean estimate of 26 Tcf for future additions
HOME	80.5	7.3		67-93		168[9]		[9]based on a mean estimate of 80 Tcf for future additions
HBOG						131.9 (117.8-131.9)		
IPAC						140[10] (29.6)[11]		[10]estimate based on its Foothills & Dome studies
								[11]Foothills area only
PAN-ALBERTA	1.0[12]							[12]established reserves under contractual control
PAN-CANADIAN	80.5			47.5	66.8	123.9 (194.8)[13]		[13]estimated ultimate potential but recommended that 123.9 be used
TRANSCANADA						140.7		

4 SUBMISSION OF AGTL

4.1 Scope of Submission

AGTL estimated Alberta's ultimate potential marketable gas expected to be economically recoverable under current technology and anticipated costs and prices from two statistical studies prepared by C. R. Winter Associates Ltd. (Winter).

AGTL also submitted a separate study, by Winter, of unconventional gas reserves in the Deep Basin area of the province.

4.2 Methodology Used

The Winter studies of undiscovered conventional gas potential were based on a log analysis of 700 randomly-selected abandoned wells situated outside of presently defined oil and gas pools and drilled after 1960. The results yielded an estimate of the frequency of occurrence and magnitude of "by-passed" gas reserves (Bcf per section) in each of nine geographical areas of the province. These estimates were multiplied by the remaining unexplored area in each of the nine study areas of Alberta to provide an estimate of undiscovered gas reserves potential.

Judgemental adjustments were made to the unexplored areas for the occurrence of oil rather than gas, and for the occurrence of oil sands and heavy oils in portions of northern and eastern Alberta, to account for the lower probable occurrence of gas in these areas.

4.3 Results

Using the above procedures, AGTL estimated the potential undiscovered gas reserves of the province to be 91 Tcf. Of this estimated undiscovered gas, AGTL estimated that under current economic and

technological conditions some 70.1 Tcf could be developed whereas the remaining 20.9 Tcf would only become marketable at significantly improved technology and higher prices. The addition of 91 Tcf of undiscovered reserves to the 80.5 Tcf of existing proved reserves, and 8.6 Tcf expected appreciation of existing reserves, yields a total ultimate recoverable gas reserve of 180.1 Tcf. AGTL maintained that it was unrealistic to recognize the 20.9 Tcf volume at this time and consequently it recommended the adoption of the 159.2 Tcf figure.

The AGTL study also suggested that the Alberta Deep Basin could yield another 30 to 48 Tcf of conventional gas reserves. However, these figures were not included in its ultimate reserve estimate.

4.4 Unconventional Reserves

A supplementary study prepared by Winter identified a gas reserve potential of more than 200 Tcf of gas-in-place in the Deep Basin area of northwestern Alberta and northeastern British Columbia. Winter indicated that 30 to 48 Tcf of marketable gas (conventional reserves) would be recoverable under today's technology and foreseeable economics. An additional 12 to 30 Tcf of gas (unconventional) would only be recoverable with future technology and much higher prices.

A detailed study of the Elmworth area in Alberta, prepared by Sovereign Engineering International, Inc., indicated the presence of both conventional and unconventional gas reservoirs. The gas-producing zones range from very high permeability conglomerates to extremely low permeability sands. It is anticipated that massive hydraulic fracturing would be required to produce the low permeability gas reservoirs.

AGTL believes that the estimates of the ultimate potential of unconventional reserves in the Deep Basin area cannot be accepted with the same degree of confidence as estimates of ultimate potential of conventional reserves, but that it would be unrealistic to completely discount these reserves over the long term.

5 SUBMISSION OF A&S

5.1 Scope of Submission

A&S did not estimate the ultimate gas potential of Alberta. In its submission, A&S analysed the Board's current method for predicting the future appreciation of the present established reserves, and suggested a figure for future appreciation.

5.2 Results

A&S found that appreciation was consistently and considerably under-estimated, and concluded that the presently established reserves of 80.5 Tcf would appreciate by approximately 14.5 Tcf. A&S stated that, for internal use, it has estimated the established reserves for the year 2000 to be 127 Tcf.

6 SUBMISSION OF AMOCO

6.1 Scope of Submission

Amoco estimated the ultimate potential of gas reserves in Alberta by combining several geological and statistical studies.

6.2 Methodology Used

In its submission, Amoco presented two independent volumetric studies for determining the ultimate potential of gas in Alberta. The first method consisted of an evaluation of well density and depth penetration to determine the potential of the unexplored areas of the province for four major horizons: the Upper Cretaceous, Lower Cretaceous, Mississippian, and Upper Devonian.

The second method consisted of a study of the undrilled volume of total rock and porous rock in each of the five major stratigraphic intervals in the Alberta basin. The assigned reserves reflect a subjective opinion of Amoco concerning the hydrocarbon potential of the untested areas.

Amoco provided an analysis of reserve appreciation and by-passed gas potential in the developed areas of Alberta. To estimate the appreciation of established reserves and the potential of by-passed gas pay, it used the statistical assumption that reserves exhibit log-normal distribution with respect to pool sizes. Amoco indicated that much of this by-passed gas would be in small pools which would be uneconomic to produce at present.

6.3 Results

Amoco stated that the numbers derived by using the two geological methods compared favourably, and it expressed confidence that 73 to 92 Tcf of marketable gas may be recovered from the undrilled portion of the Alberta basin.

From its analysis, Amoco estimated the appreciation of established reserves to be 11 to 16 Tcf. The development of by-passed pay was indicated to yield an additional 30 to 35 Tcf of gas.

By adding these values to the currently established reserves of 80 Tcf, Amoco estimated the total ultimate potential of conventional gas in Alberta to be between 194 and 223 Tcf.

6.4 Unconventional Reserves

Amoco stated, in a supplemental submission regarding tight formation gas, that a substantial unconventional gas reserve potential exists in the tight Cretaceous sands of the Alberta portion of the Deep Basin. The low permeability sands differ significantly from the more conventional and permeable sand and conglomerate reservoirs found within the same Cretaceous sand sequence. Based on experience in similar tight gas sand reservoirs, Amoco indicated that sustained commercial gas production from these sands can be obtained only as a result of massive hydraulic fracturing (MHF).

Amoco estimated the total gas-in-place reserves of the tight Cretaceous sands to be 274 Tcf. It indicated that none of these reserves is economically recoverable at today's producer net-backs. Amoco expressed the opinion that either an improvement in today's technology or the development of new technology could result in some 116 Tcf being marketed at today's prices. With a 100 per cent increase in producer net-backs, it indicated that some 192 Tcf of gas would be ultimately recoverable over a 44-year life.

7 SUBMISSION OF CANADIAN HUNTER

7.1 Scope of Submission

Canadian Hunter did not submit an estimate of Alberta's total ultimate gas potential, but confined its estimates to the Elmworth/Wapiti and the Alberta Deep Basin areas. Its ultimate gas potential estimates for these areas were segmented to reflect changes in economics and differing reservoir rock qualities. Necessary technological developments were also discussed.

Reserve summaries and net pay maps for the Cadotte and Falher zones in the Elmworth/Wapiti area were submitted along with a deliverability forecast.

7.2 Methodology Used

Canadian Hunter conducted a detailed analysis of logs, cores and tests from 20 productive zones in 57 wells in the Elmworth/Wapiti region. Net pay maps were then developed for proven, probable and possible reserves. Recoveries for different price and technological improvements were predicted using mathematical simulation studies. The total reserves (proven, probable and possible) were summed to determine the ultimate potential of this region. Canadian Hunter's method of estimating Alberta's Deep Basin ultimate reserves is described in a scientific paper by J. A. Masters[1] which outlines the measurement of the gas-saturated deep basin by computer assisted analytical techniques.

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1 Masters, John A., 1979, Deep Basin Gas Trap, Western Canada: AAPG Bull., V. 63/2, pp. 151-181.

7.3 Results

Canadian Hunter predicted that, of the estimated 360 Tcf in the Alberta Deep Basin, 30 Tcf could be recovered with current technology and price, an additional 60 Tcf could be recovered at an advanced price ($2.00 to $2.50 per Mcf net-back plus escalation), and a further recovery of 174 Tcf could be achieved with reasonable economic incentives ($3.50 per Mcf net-back plus escalation) and improved technology. This gave an ultimate potential for Alberta's Deep Basin of 264 Tcf.

By making a comparison with the Elmworth study area, Canadian Hunter inferred that, in the Alberta Deep Basin, 38 Tcf of the 264 Tcf will be produced from rocks with greater than 15 per cent porosity, 82 Tcf from rock with between 11 and 15 per cent porosity, and 144 Tcf from rock with porosity below 11 per cent.

8 SUBMISSION OF CANADIAN-MONTANA

8.1 Scope of Submission

Canadian-Montana submitted an evaluation of remaining marketable proven and possible ultimate natural gas reserves for a limited portion of southeastern Alberta, corresponding to the areas where it removes gas from Alberta under Alberta Permit CM 76-3.

Total remaining marketable proven natural gas reserves of the study area were estimated to be 0,329 Tcf. The maximum deliverability forecast of ultimate marketable gas reserves for the study area to the year 2000 are 0.757 Tcf.

9 SUBMISSION OF CPA

9.1 Scope of Submission

CPA estimated the ultimate potential of conventional marketable gas based on current technology and favourable economic return. This potential was evaluated by a number of contributing companies, on a proprietary basis.

9.2 Methodology Used

CPA subdivided the geological section of Alberta into seven major segments. The Foothills area was analysed separately. Each of the contributing companies used one or a combination of the following methods in its estimate of the ultimate potential for its particular area of concern:

- play horizon analysis,
- volumetric extrapolation, and
- well density extrapolation.

The choice of methods depended on the character of the geology and the degree of development of that particular segment. This analysis resulted in the generation of a range of undiscovered raw gas-in-place and a range of undiscovered marketable gas reserves for each geologic section.

Well density plots were developed for each area as a means of analysing the level of confidence in the range of estimates. CPA contended that the frequency and distribution of past drilling activity provided a rough assessment as to the degree of control and evaluation for that particular segment in terms of the only ultimate analysis method, drilling.

Each segment, or a portion of a segment, was also analysed using the Monte Carlo simulation technique. Variables used in the Monte Carlo simulation varied from segment to segment and were based on the results of historical data analysis coupled with the individual company's judgement based on its direct knowledge and intuition concerning a particular area. This analysis technique generated a probability-related range in the undiscovered initial reserve value for each area.

9.3 Results

Using a combination of the techniques previously mentioned, CPA estimated that the undiscovered marketable gas reserves could vary from 46 Tcf (at 95 per cent probability) to 87 Tcf (at 5 per cent probability). Based on a mean value of 67.5 Tcf and an established reserve of 83.5 Tcf (including 6 Tcf appreciation), CPA estimated the total ultimate potential of conventional gas in Alberta to be 151 Tcf.

9.4 Unconventional Reserves

CPA submitted that there is little doubt concerning the presence of extremely large in-place reserves in the 30 000 cubic mile portion of tight Mesozoic section sediments in the Deep Basin. The geological and reservoir continuity of these sediments suggested a low risk on an in-place reserve assessment basis but a high risk as to assured marketable reserves in view of the technological uncertainty as to the ultimate recovery response from this area. Consequently, CPA did not make any estimates for the ultimate potential of unconventional reserves.

10 SUBMISSION OF DOME

10.1 Scope of Submission

Dome commissioned the consulting firm of Kloepfer & Associates Ltd. (Kloepfer) to prepare an independent study of the ultimate natural gas potential of Western Canada and used it as a basis of its submission.

10.2 Methodology Used

Kloepfer divided Alberta into 10 geographic areas and then evaluated the potential of 10 major stratigraphic horizons in each area. Basic reserve, drilling and volume of sediments data were generated for each area and these were reviewed in light of regional geology and exploration maturity. The ultimate potential of each area in the Kloepfer report was generated using the following methods:

- volume of sediments,
- finding rates extrapolations, and
- "best-guess" interpretation.

10.2.1 Volume of Sediments

Kloepfer utilized a set of basic assumptions regarding the relationship of drilled versus undrilled sediments. It assumed that each well drilled explored one square mile of sediments and that unexplored sediments were equal in potential to explored sediments. It proposed that the volume of sediments method may be valid in setting upper limits on the gas which would be found in partly explored areas such as Alberta.

Although the ultimate gas potential using the volume of sediments method was calculated for each of the 10 areas in Alberta, the combined upper limit result was not presented.

10.2.2 Finding Rates Extrapolations

In this method the remaining footage required to be drilled in a zone to obtain an ultimate drilling density was calculated. Near term finding rates in Mcf per foot drilled, usually based on rates achieved over the period from 1971 to 1976, were applied to the footage to be drilled. The ultimate gas potential of each of the 10 areas and formation groups was thus calculated. The ultimate gas potential using this method is 140 Tcf.

10.2.3 Best-Guess Estimate

A "best-guess" ultimate gas potential was assigned each of the areas, based on the "maximum" based on volumes of sediments, the finding rates methods, and geological expectations for each study area.

10.3 Results

Kloepfer, in its Ultimate Gas Potential Study, and Dome, during testimony at the hearing, expressed the view that the volume of sediments estimates were not meaningful, or even realistic. Dome stated that the final best-guess estimates are based on the two methodologies used by Kloepfer and subjective geological judgement, and that the best-guess estimate was generally a rounding of the finding rate estimate to the nearest Tcf. On these considerations, Dome estimated the ultimate potential of recoverable marketable gas in Alberta to be 137.1 Tcf on an as is basis (145 Tcf on a 1000 Btu basis).

11 SUBMISSION OF ESSO

11.1 Scope of Submission

Esso estimated the ultimate gas potential in Alberta using a statistical approach. The estimated volume is expected to be recoverable under current and anticipated gas pricing and with existing technology.

11.2 Methodology Used

Esso divided the geological section of Alberta into 26 segments. In each segment, Monte Carlo simulation was used to combine the pool size range, the number of pools, and the risk factor to calculate the future reserve additions for that unit. The ranges of future reserve additions in 26 segments were summed by Monte Carlo simulation to give the range of the provincial future gas discoveries.

Pools size in each segment was derived from historical data. The number of pools, the range of pool size, and the risk factor for future discoveries were derived from best available information and geological judgement. The economic conditions were a component of the geologists' judgement concerning the number of pools and the risk factor for future discovery.

11.3 Results

Using this procedure, Esso estimated that future gas discoveries could vary from 16.3 Tcf (at 95 per cent probability) to 47.1 Tcf (at 5 per cent probability). The mean value of future gas discoveries was estimated at 26 Tcf, resulting in an ultimate potential of some 109.6 Tcf on an as is basis (114 Tcf on a 1000 Btu basis).

11.4 Unconventional Reserves

Esso stated that development of unconventional gas from Deep Basin tight reservoirs and Cretaceous coal-bearing strata require significantly improved technology. This development will occur very slowly unless there is an available market and a favourable business environment. Gas from unconventional reservoirs was not included in its ultimate potential estimate.

12 SUBMISSION OF HOME

12.1 Scope of Submission

Home estimated the ultimate gas potential in Alberta using an estimated range of ultimate gas potentials for geological plays in which undiscovered gas is expected.

12.2 Methodology Used

Home divided the Alberta geological column into 24 exploration plays. Two of these plays were evaluated using the Monte Carlo simulation technique. A range of volumes was derived by making use of reservoir volumetric data and geological concepts regarding the number of prospects and the chance of gas occurrence. Minimum, most likely, and maximum values were used to produce triangular probability distributions for each of 10 variables. Play probability estimates were made by combining these with a Monte Carlo simulator.

Four Lower Cretaceous and Jurassic plays of southern Alberta were analysed by the areal yield factor method. Home assumed that the square of the number of drilled sections per township equals the number of evaluated sections. The total proven reserves for each play was applied to the number of evaluated sections to derive a yield factor. This yield factor was then multiplied by the number of unevaluated sections to determine the amount of undiscovered gas. A range of potentials was provided by varying the well density to evaluated sections relationship.

12.3 Results

The current established reserves and appreciation were taken directly from ERCB reports. On this basis, Home believed there is a 90 per cent chance that the ultimate gas potential of Alberta will be 151

Tcf, a 50 per cent probability of it being 165 Tcf and a 10 per cent probability of it being 185 Tcf.

No estimate was made on the potential for gas reserves from unconventional sources.

13 SUBMISSION OF HBOG

13.1 Scope of Submission

HBOG presented a study which analysed performance relationships using reserves and drilling data from the Kloepfer & Associates Ltd. study entitled "Ultimate Gas Potential of Western Canada", to estimate Alberta's ultimate gas potential. The estimates did not include the potential of unconventional low permeability reservoirs.

13.2 Methodology Used

For each of 10 geographic areas of Alberta, HBOG used polynominal curve fitting techniques to develop and extrapolate an empirical relationship between historical reserve estimates and cumulative exploratory drilling.

Ultimate exploratory drilling densities were selected and used to calculate ultimate exploratory footage. The empirical relationships between reserves and drilling were extrapolated to the ultimate exploratory footage to determine the ultimate reserve potential.

13.3 Results

HBOG estimates the ultimate potential of marketable gas to be 131.9 Tcf on an as is basis (137 Tcf on a 1000 Btu basis). The entire northeastern area of Alberta was not analysed using the curve fitting technique; consequently, 1 Tcf was assigned for the potential of this area. HBOG believes that appreciation of existing reserves accounts for almost 15 Tcf of the 137 Tcf ultimate potential.

14 SUBMISSION OF IPAC

14.1 Scope of Submission

In reviewing the Kloepfer study of the ultimate gas potential of Western Canada, prepared for Dome, IPAC expressed some concern with the results of the Kloepfer approach to the geologically complex Foothills area of Alberta. IPAC indicated that the Foothills area is one of the most lightly explored areas of Alberta having significant potential and that it would be an area where a statistical projection of ultimate gas potential might be unreliable. IPAC therefore commissioned Kloepfer & Associates to conduct a special geological study of the Foothills.

14.2 Methodology Used

The Kloepfer study is based on the detailed geological mapping conducted by Veezay Geodata Ltd. (Veezay) over a portion of the Foothills disturbed belt in Alberta. Four prospective zones were evaluated in the study, the Lower Cretaceous, Triassic, Mississippian, and the Upper Devonian. Various sources of geological data were used in the Veezay studies to develop a series of geological cross-sections and structure-contour maps over the length of the disturbed belt. Using the cross-sections, structure maps were developed and used to identify the location, size and closures of 312 potential subsurface structures in the four prospective zones. Used in conjunction with computer generated porous-footage isopach maps defined from existing formation and pool data, a total potential resource figure was defined for each geological horizon. This potential was then classified into two categories - economic or potentially economic. Results from the study area were extrapolated to the southern portion of the Foothills, which was not included within the study.

14.3 Results

On the basis of the geological study, IPAC estimated an ultimate reserve potential of 29.59 Tcf for the Foothills region of Alberta. This amount is comprised of 10.19 Tcf of recognized reserves in discovered pools and 19.4 Tcf of potential resources. Of this, 15.3 Tcf has been classified as currently economic with 4.1 Tcf being potentially economic.

IPAC was of the opinion that, as only four horizons and only structural traps were analysed, a significant increase to the 29.59 Tcf ultimate gas potential for the Foothills is possible.

On the basis of this additional work done for the Foothills region, and the previously described Dome studies, IPAC recommended that the Board adopt an ultimate reserve estimate for Alberta of at least 140 Tcf.

15 SUBMISSION OF PAN-ALBERTA

15.1 Scope of Submission

Pan-Alberta did not address the question of ultimate gas potential. However, it submitted detailed documentation of established gas reserves under its contractural control. Established gas reserves were estimated at 1.024 Tcf.

16 SUBMISSION OF PAN-CANADIAN

16.1 Scope of Submission

Pan-Canadian presented estimates of Alberta's ultimate and current gas potential based on "gas expected to be economically recoverable under current technology and anticipated costs and prices". Gas from unconventional sources that requires "significantly improved technology" was not included.

16.2 Methodology Used

Pan-Canadian divided the province into five geological-geographical areas. For each of these areas it evaluated the known productive areas, conducted basic "play" evaluations, and subjectively projected these trends to the surrounding areas to determine ultimate potential. The estimated ultimate potential gas reserves included proved, probable, and possible reserves. Pan-Canadian adjusted the ultimate potential to determine a more conservative estimate of current potential and recommended its use by the Board in establishing gas policies as they affect Alberta.

16.3 Results

Pan-Canadian estimated that 114.3 Tcf of marketable gas would ultimately be added to Alberta's gas reserves. Correspondingly, the ultimate gas potential of Alberta was judged to be 194.8 Tcf. Pan-Canadian also calculated that 70 per cent of the ultimate gas potential will be from Mesozoic sediments.

The Deep Basin area, as identified by Pan-Canadian, includes more area than identified by other companies. It estimated the ultimate gas potential of this area to be 102.6 Tcf. This ultimate potential is considered to be in conventional reservoirs.

Pan-Canadian proposed a current potential which is made up of 100 per cent of its proved reserves, 75 per cent of its probable reserves and 25 per cent of its possible reserves. The current potential is thereby estimated to be 123.9 Tcf, a value it recommended for adoption by the Board as the ultimate gas potential for the province.

17 SUBMISSION OF TRANSCANADA

17.1 Scope of Submission

TransCanada estimated the ultimate potential gas reserve of Alberta using statistical methods and assuming current economics and technology.

17.2 Methodology

TransCanada derived its ultimate reserve estimates by using the last 10 years' drilling and reserve statistics. It used least squares best fit curves to correlate the ratio of reserves to cumulative gas well mileage, versus cumulative gas well mileage in nine areas of the province, and for the province as a whole.

17.3 Results

TransCanada estimated the provincial ultimate gas reserve to be 140.7 Tcf. However, using the nine different areas with area trends, the total ultimate reserve was found to be 129.4 Tcf. If the provincial trend were applied to the last data point of each area, the provincial ultimate reserve was estimated to be 132.7 Tcf.

The preceding represents the findings of the division of the Board which considered the matter of the ultimate potential for gas in Alberta at a hearing in February, 1979.

V. Millard
Chairman

G. J. DeSorcy, P.Eng.
Vice Chairman

N. Strom, P.Eng.
Board Member

DATED at Calgary, Alberta
this 20th day of November 1979.

APPENDIX A.1

FORM OF NOTICE OF HEARING

ENERGY RESOURCES CONSERVATION BOARD

THE OIL AND GAS CONSERVATION ACT

THE GAS RESOURCES PRESERVATION ACT

PROCEEDING NO. 780491

NOTICE OF HEARING

ULTIMATE RESERVES OF GAS AND CO-PRODUCTS
ALBERTA GAS SUPPLY PROTECTION FORMULAE

WHEREAS the Energy Resources Conservation Board will conduct a two-phase public hearing respecting (a) Phase I - the ultimate reserves of gas and co-products in Alberta, and (b) Phase II - the formulae for determining the amount of gas surplus to Alberta needs.

THEREFORE TAKE NOTICE that the Energy Resources Conservation Board will hold a public hearing at the Court House, 611 - 4 Street S.W., Calgary, Alberta, on Tuesday, 13 February 1979, at the hour of 9:00 a.m., for the purpose of hearing representations respecting Phase I described above. While the Board does not wish to restrict the content of submissions, for convenience in interpretation the Board asks that:

1. all estimates be on an initial basis - i.e. before production;

2. estimates be clearly identified as in-place raw gas and recoverable marketable gas;

3. where convenient, estimates of both in-place raw gas and recoverable marketable gas be classified as to

   (a) gas expected to be economically recoverable under current technology and anticipated costs and prices,

divided as to

   (i) appreciation of reserves considered proved as of 31 December 1977, and reported on in ERCB Report 78-18, and

   (ii) new discoveries;

   (b) gas expected to be economically recoverable only under significantly improved technology divided as to

(i) appreciation of reserves considered proved as of 31 December 1977, and reported on in ERCB Report 78-18, and

(ii) new discoveries;

4. to the extent practical, estimates be supported by discussions of geological setting, results of recent exploration, trends in exploration and production technology, trends in costs and prices, and expected reservoir conditions (such as size, entrapment, rock quality and depth).

Although the above guidelines relate to Alberta's ultimate reserves of gas in the entire Province, the Board would welcome any submission which addressed itself only to specific areas or parts of the Province.

The Board would also appreciate receiving submission respecting the initial ultimate recoverable reserves of co-produced ethane, propane, butanes, pentanes plus, and sulphur classified as in item 3 above.

Any person making submission with respect to Phase I of the hearing shall file on or before 15 December 1978, twenty copies of his submission with the Board at 603 - 6 Avenue S.W., Calgary, Alberta, T2P 0T4. A copy of each submission may be inspected at the Board's Records Centre after 20 December 1978, or may be obtained from the submitter by interested persons upon request.

Any person intending to make a submission in response to a submission filed in accordance with the last preceding paragraph shall file, on or before 1 February 1979, twenty copies of his submission with the Board and two copies of the submission with the person to whose submission he is responding at the address set out in that person's submission.

FURTHER TAKE NOTICE that the Energy Resources Conservation Board will hold a public hearing at the Court House, 611 - 4 Street S.W., Calgary, Alberta, on Tuesday, 13 March 1979, at the hour of 9:00 a.m., for the purpose of hearing representations respecting Phase II described above.

The hearing will not deal with the basic policy of protection for the present and future needs for gas of persons within the Province as provided for in The Gas Resources Preservation Act, but will consider modifications to the formulae and procedures currently used by the Board in the administration of the Act.

Representations will be heard on the Board's procedures for determining:

1. Alberta's present and future requirements of gas over the future protection period, and

2. The supply of gas which should be available above existing or new gas removal permit commitments to provide adequately for the requirements described in item 1.

The Board staff will file a submission by 30 October 1978, outlining the current formulae and procedures and commenting on certain of the factors involved, and outlining some possible alternative administrative practices.

Any person making submission with respect to Phase II of the hearing shall file on or before 3 January 1979, twenty copies of his submission with the Board at 603 - 6 Avenue S.W., Calgary, Alberta, T2P 0T4. A copy of each submission may be inspected at the Board's Records Centre after 8 January 1979, or may be obtained from the submitter by interested persons upon request.

Any person intending to make a submission in response to a submission filed in accordance with the last preceding paragraph shall file, on or before 20 February 1979, twenty copies of his submission with the Board and two copies of the submission with the person to whose submission he is responding at the address set out in that person's submission.

DATED at Calgary, Alberta on 29 August 1978.

ENERGY RESOURCES CONSERVATION BOARD

A. L. McLarty
Board Solicitor

APPENDIX A.2

DEFINITIONS

CONVENTIONAL RESERVES	Those gas reserves which are recoverable in commercial quantities under today's economics without application of any technology other than that usually associated with normal gas well completions.
UNCONVENTIONAL RESERVES	Those gas reserves which would not be recovered under existing economic conditions and using current existing technology.
DEEP BASIN AREA	In Alberta, a portion of the western sedimentary basin characterized by rapid thickening of the Mesozoic section. Canadian Hunter uses the term to describe an area southwest of Grande Prairie and east of the Foothills belt.
ULTIMATE POTENTIAL*	An estimate of the initial established reserve which will become developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions.
MASSIVE HYDRAULIC FRACTURING (MHF)	A technology applied to very low permeability reservoirs to create artificial fractures in the pay section to improve reservoir productivity. Much larger volumes of injected fluid and propping agent are used in MHF than in normal fracture treatments.

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* Definition recommended by the Joint Task Force on Uniform Reserves Terminology, 1978.

A3 TABLE OF FORMATIONS, ALBERTA